CALIFORNIA ENERGY COMMISSION

2002 MONTHLY ELECTRICITY FORECAST: CALIFORNIA SUPPLY/DEMAND CAPACITY BALANCES FOR MAY-DECEMBER
Documentation of Baseline Assumptions and Principal Uncertainites

Report is an update to November 2001 Report - publication # 700-01-002

STAFF REPORT

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CALIFORNIA ENERGY COMMISSION

Denny Brown
Principal Author

Karen Griffin
Manager
Electricity Analysis Office

Bob Therkelsen
Chief Deputy Director
Systems Assessments
and Facilities Siting Division

Steve Larson
Executive Director

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The ***2002 Monthly Electricity Forecast: California Supply/Demand Capacity Balances For May- December*** was prepared with the contribution of the following:

Project Managers
Karen Griffin
Denny Brown

Principal Author
Denny Brown

Technical Assistance

Richard Jensen	Ron Wetherall	Al Alvarado
Laiping Ng	Jim Hoffsis	Angela Tanghetti
Judy Grau	Jim Woodward	David Vidaver
Tom Gorin	Lynn Marshall	Roger Johnson
Barbara Byron	Joel Klein	

Support Staff
Sue Hinkson

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Executive Summary

This outlook provides the current Energy Commission staff assessment of available statewide electricity supplies and the likely peak electricity demand scenarios for each month between May and December of 2002. The purpose of this outlook is to illustrate whether the existing system and new capacity additions currently under development are sufficient to serve California's capacity needs under a reasonable set of physical and financial conditions. The staff has been working with stakeholders and the California Independent System Operator staff to refine the baseline assumptions, which are based on the best available data. This outlook is an update of the staff resource assessment that was released in November 2001 (P700-01-002).

In addition to providing the monthly outlook, the report also documents the information sources and assumptions used for the supply adequacy assessment. The report includes information on two key demand uncertainties and one supply-side uncertainty. Overall, this year's electricity demand levels will heavily depend on the degree that observed 2001 conservation patterns are carried forward. The range of this uncertainty is included in the demand assessment scenarios. Since California's summer peak demand is largely a function of air conditioning, several temperature scenarios are also included in the assessment.

Because the report is focused on capacity adequacy, it embodies planning for adverse conditions that might strain the resources of the system. However, it also tries not to be too conservative, because acquiring additional resources to meet extremely unlikely conditions would result in increased costs to ratepayers and potentially create unnecessary environmental impacts.

The Energy Commission staff expects that, under baseline conditions, sufficient resources will be available to meet 2002 statewide peak loads and required operating reserves in the event of a very hot summer (1-in-10 probability). Baseline conditions include the completed construction of new gas-fired and renewable resources. **Figure 1** provides a summary outlook for summer 2002.

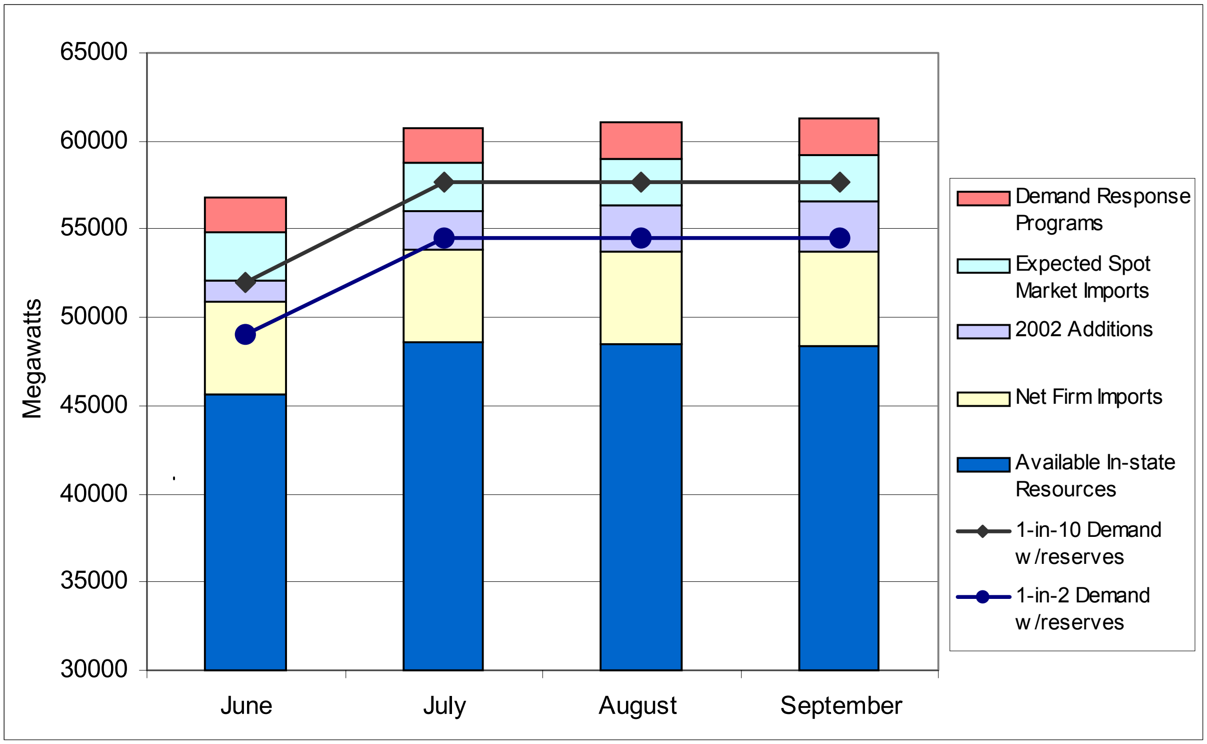
Demand reductions by California's electricity consumers, new generation sources and mild temperatures averted outages during the summer 2001. **Figure 1** shows that the supply outlook continues to be favorable for maintaining reliability this year under normal weather conditions and with the possibility of having a hot summer.

The California ISO has a similar 2002 outlook for their control area under normal summer weather conditions. They expect higher operating margins than in recent years.[1] According to the California ISO, if there is a hotter-than-expected summer,

[1] Operations Engineering, California ISO, 2002 Summer Assessment - Version 1.0, April 25, 2002.

they may need to rely on increased imports and emergency mitigation measures to maintain required operating reserves within their control area.

Figure 1
California Electricity Outlook for Summer 2002



The Energy Commission staff outlook includes 2,586 MW of new generation facilities coming on line by August 1, 2002. August is the period when the California peak demand typically occurs. There will be continued opportunities to purchase additional electricity supplies from western regional spot markets. Finally, system operators will have a sufficient menu of emergency mitigation measures that can be implemented if reserve margins fall below standard operation requirements.

Summer 2002 Supply and Demand Outlook

The Energy Commission staff expects that, under baseline conditions, sufficient resources will be available to meet 2002 statewide peak loads and required operating reserves in the event of a very hot summer (1-in-10 probability).

Table 1 provides the detailed 2002 monthly supply and demand forecast for California for May through December. A description of the sources of information and assumptions used for each line of the table is provided below.

The supply and demand forecast does not address the problem of moving the electricity to major load centers, therefore local area reliability issues may continue to exist during the forecast period. The California ISO identifies several of these areas through the Local Area Reliability Study (LARS) process.

Table 1

2002- California Electricity Supply - Peak Demand Balance (MW) On First Day Of The Month

#		May	June	July	August	September	October	November	December
1	**CEC 2002 Baseline Forecast (1-in-2 Weather)**	**41,101**	**46,312**	**51,277**	**51,277**	**51,277**	**42,141**	**37,833**	**39,189**
2	**1-in-10 Weather Adjustment[1]**	**1,407**	**2,683**	**2,971**	**2,971**	**2,971**	**1,443**	**-**	**-**
3	**1-in-2 Operating Reserve**	**2,538**	**2,876**	**3,223**	**3,223**	**3,223**	**2,667**	**2,365**	**2,460**
4	**1-in-10 Reserve Adjustment[1]**	**98**	**187**	**220**	**220**	**220**	**101**	**-**	**-**
5	**California Statewide Peak Demand + Operating Reserve**	**45,144**	**52,058**	**57,691**	**57,691**	**57,691**	**46,352**	**40,198**	**41,649**
6	Existing ISO Control Area Merchant Thermal	20,651	20,919	20,910	20,896	20,889	20,643	20,666	20,665
7	ISO Municipal Utility Thermal Resources	1,464	1,461	1,461	1,461	1,461	1,465	1,465	1,465
8	ISO Control Area Hydro	11,161	11,194	11,192	11,189	11,164	11,105	11,102	11,105
9	IOU Retained Generation	5,291	5,291	5,291	5,291	5,291	5,291	5,291	5,291
10	Net Imports ISO Control Area	4,850	5,231	5,231	5,231	5,231	4,046	4,050	4,050
11	Dependable QF Capacity	5,923	5,999	5,973	5,948	5,911	5,754	5,670	5,670
12	LADWP Control Area Resources	8,056	8,099	8,099	8,099	8,099	8,056	8,056	8,056
13	Imperial Irrigation District + Other Non ISO Municipals	992	996	1,013	1,013	1,013	997	1,000	1,004
14	**Existing Resources and Dependable Imports**	**58,388**	**59,190**	**59,169**	**59,128**	**59,059**	**57,358**	**57,301**	**57,307**
15	Hydro Derate[2]	(2,500)	(1,500)	(1,500)	(1,500)	(1,500)	(2,500)	(2,500)	(2,500)
16	Estimated Nuclear Off-Line	(2,143)	(1,070)	-	-	-	-	-	-
17	Economic Outages	-	-	-	-	-	-	-	-
18	SCR Retrofit	(1,332)	(1,091)	-	-	-	(110)	(110)	(110)
19	Estimated Outages	(5,754)	(3,550)	(3,550)	(3,550)	(3,550)	(6,140)	(8,410)	(7,265)
20	**Estimated Forced & Scheduled Outages**	(11,729)	(7,211)	(5,050)	(5,050)	(5,050)	(8,750)	(11,020)	(9,875)
21	**Existing Resources Available to Meet Load**	**46,660**	**51,979**	**54,119**	**54,078**	**54,009**	**48,608**	**46,281**	**47,432**
22	**Resource Surplus/Deficit Before Additions**	**1,516**	**(79)**	**(3,572)**	**(3,613)**	**(3,682)**	**2,256**	**6,083**	**5,783**
	Generation Additions (Summer Dependable MW) 75% Probability								
23	2002 Additions	962	1,676	2,224	2,586	2,867	3,139	3,170	3,184
24	**Total Generation Additions@75% Probability**	**962**	**1,676**	**2,224**	**2,586**	**2,867**	**3,139**	**3,170**	**3,184**
25	**Resource Surplus/Deficit Before Demand Response**	**2,477**	**1,596**	**(1,348)**	**(1,027)**	**(815)**	**5,395**	**9,253**	**8,967**
26	**Planning Reserve Margin (1-in-2 Weather)**	18%	18%	11%	12%	12%	25%	34%	33%
27	**High Temperature Scenario Reserve Margin (1-in-10 Weather)[1]**	14%	11%	4%	5%	5%	21%		
28	**Expected Spot Market Imports**	2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700
29	**Resource Surplus/Deficit With Spot Market Imports**	**5,177**	**4,296**	**1,352**	**1,673**	**1,885**	**8,095**	**11,953**	**11,667**
30	**1-in-10 Reserve Margin Including Expected Spot Market Imports[1]**	21%	17%	10%	10%	11%	27%	42%	40%
31	**Demand Responsive Programs**								
32	Ongoing Programs	4	4	4	4	4	4	4	4
33	Interruptible/Emergency Programs	1,096	1,382	1,382	1,382	1,382	1,096	1,096	1,096
34	Existing Voluntary/Emergency Programs	658	658	658	658	658	658	658	658
35	**Demand Responsive Program Total**	**1,758**	**2,044**	**2,044**	**2,044**	**2,044**	**1,758**	**1,758**	**1,758**
36	**Resource Surplus/Deficit**	**6,935**	**6,341**	**3,397**	**3,718**	**3,930**	**9,853**	**13,711**	**13,425**
37	[1] 1-in-5 weather adjustment in May and October								
38	[2] Based on CEC 2002 confidential data. Normal operations derate (-2,500 MW) + peak operation option (+1000 MW).								

Lines 1 and 2 Peak Demand Forecast

Actual Peaks:

California benefited from a significant decline in peak demand during 2001 caused by voluntary conservation, slowing of the economy, demand responsiveness programs and fewer very hot days. The historic statewide peak demand since 1998 is provided in **Table 2**.

Table 2
Historic Peak Demand (MW)

Year	Statewide Peak Demand
1998	53,119
1999	53,163
2000	52,588
2001	47,820

1998: Includes 1,337 MW of interrupted non-firm load.
2000: Includes 1,710 MW of interrupted non-firm load.

Temperature-related and Consumer Behavior-related Uncertainties:

The California Energy Commission developed a forecast of the annual statewide peak demand corresponding to temperature conditions that have a 1-in-2, 1-in-5, 1-in-10 and 1-in-40 probability of occurring. The 1-in-2 probability represents an average summer temperature scenario, while a 1-in-10 probability is the chance that there will be a very hot summer. The 1-in-40 is the outlying possibility that there would be a persistent and west-wide heat wave. In addition, the forecast includes three possible demand scenarios under each temperature condition for 2002 to reflect different conservation assumptions. The demand forecast was developed assuming normal economic growth trends. The forecast does not include the economic downturn in 2001 or any of the effects of the September 11 tragedy. Details on the demand forecasts can be found in *The 2002-2012 Electricity Outlook Report*. **Table 3** provides the statewide peak demand forecast for each scenario under various temperature conditions.

Table 3
2002 Statewide Coincident Peak Demand Forecast Scenarios (Summer MW)

	Low	Most Likely	High
1-in-2	50,501	51,277	54,255
1-in-5	52,229	53,033	56,113
1-in-10	53,425	**54,248**	57,402
1-in-40	54,629	55,471	58,697

Source: California Energy Demand 2002-2012 Forecast, September 2001

The Climate Prediction Center of the National Oceanic and Atmospheric Administration provides a seasonal temperature and precipitation outlook that is published on their Website.[2] The latest NOAA outlook shows that there is a 38 percent chance that the May through July California temperatures will be above average compared to a 33 percent chance that there will be normal conditions. The NOAA outlook is not represented as a firm forecast since the outlook is based on El Niño oscillation observations and it is difficult to predict actual circulation patterns.

The Energy Commission staff used the 1-in-10 temperature probability to estimate the summer peak demand levels to assess a conservative electricity supply scenario.

Consumer-Related Demand Adjustments:

One major uncertainty in this demand assessment pertains to the energy conservation behavior of California businesses and residents. It is difficult to determine how many of the actions taken by electricity consumers last summer will continue into 2002. Monthly peak demand in 2001 was significantly lower than expected due to voluntary conservation activities and state-sponsored demand reduction programs. Determining the amount of this reduction that was a result of permanent technological improvements (e.g., installing compact florescent lamps or an Energy Star refrigerator) or temporary behavioral changes (e.g., turning up the thermostat to reduce use of air conditioning) is difficult.

If the reductions in electricity peak demand are due to changes in behavior, then the savings may disappear when consumers return to previous behavior patterns. If the reductions are due to equipment changes, these savings should continue. The Energy Commission staff prepared three scenarios to account for possible demand reduction patterns. These patterns are based on alternative assumptions about the level and persistence of voluntary and permanent program impacts.

[2] The latest NOAA seasonal temperature outlook can be found at: [http://www.cpc.ncep.noaa.gov/products/predictions/multi_season/13_seasonal_outlooks/color/seasonal_forecast.html]

The “Most Likely” scenario in **Table 3** assumes there is a moderate increase in permanent program impacts and nearly a fifty-percent decline in voluntary demand reductions. The “Low” scenario assumes that there is a moderate growth in permanent program impacts and slow decline in voluntary reductions of demand. The “High” scenario assumes that voluntary reductions do not persist.

Temperature-Related Demand Adjustments:

California electricity peak demand levels are driven by temperature. Air conditioning contributes to a large portion of the California summer peak demand. Using temperature data collected since 1962, the Energy Commission staff classifies temperature conditions according to the probability of occurrence. The temperature record is then correlated with peak demand and used as an adjustment factor for projections. This allows the Energy Commission to consider a range of possible demand scenarios when conducting supply adequacy studies.

Peak electricity demand does not always occur in the hottest day of the year. There is a strong correlation between peak electricity demand and a buildup of high temperatures over several days. **Figure 2** illustrates the Weighted Statewide 3-Day Moving Average High Temperatures used in the current peak demand forecast. Temperatures are recorded for each climate zone in the state. In creating the 3-Day moving statewide average, the temperature for each climate zone is weighted by the number of air conditioners in the zone.

Monthly demand for non-summer months is estimated based on the monthly historic average percent of annual peak multiplied by the 1-in-2 forecasted peak. Staff used the 1-in-5 condition to account for the historic temperature variability in May and October and the 1-in-10 temperature condition to forecast demand during summer months. June is based on its historic average percent of annual peak multiplied by the forecasted peak.

The supply/demand balance table assigns an equal probability that the annual peak could occur in July, August, or September. The historic average percent of peak allocations in **Table 4** is used to calculate the monthly demand in **Table 5**.

Figure 2
Ranking of AC Weighted Statewide 3-Day Moving Average High Temperatures

	Year	Average High Temp. (Degrees Fahrenheit)	Probability
1	1991	92.9	1-in-40 Temp 93.1 degrees or less
2	1964	93.3	1-in-20 Temp 93.75 degrees or less
3	2001	94.6	
4	1963	94.8	1-in-10 Temp 94.8 degrees or less
5	1989	94.9	
6	1962	95.1	
7	1968	95.2	
8	2000	95.3	1-in-5 Temp 95.3 degrees or less
9	1975	95.8	
10	1965	96.4	
11	1999	96.9	
12	1990	96.9	
13	1979	97	
14	1966	97.1	
15	1973	97.2	
16	1986	97.6	
17	1971	97.9	
18	1974	98	
19	1970	98	
20	1985	98.2	1-in-2 Temp 98.7 degrees or less
20	1995	99.2	1-in-2 Temp 98.7 degrees or more
19	1977	99.6	
18	1978	99.6	
17	1987	99.7	
16	1982	100	
15	1972	100.1	
14	1969	100.2	
13	1996	100.2	
12	1993	100.2	
11	1980	100.6	
10	1994	100.7	
9	1976	100.9	
8	1992	101.1	1-in-5 Temp. 101 degrees or more
7	1967	101.1	
6	1997	101.2	
5	1984	101.4	
4	1983	101.5	1-in-10 Temp 101.5 degrees or more
3	1998	101.9	
2	1981	102.2	1-in-20 Temp 102.15 degrees or more
1	1988	103.4	1-in-40 Temp 102.8 degrees or more

40 year average temp. = 98.4

Table 4
1993 - 2001 CA ISO Monthly Peak Electricity Demand as A Percentage of Annual Peak (MW)

	1993	1994	1995	1996	1997	1998	1999	2000	2001	Average	Percent
January	27,216	25,200	29,444	26,962	27,788	27,078	31,419	32,774	32,623	28,945	73%
February	25,024	25,396	28,155	26,571	25,837	26,267	31,532	32,394	30,683	27,984	71%
March	24,360	24,754	27,862	25,767	27,289	26,106	31,146	32,552	29,778	27,735	70%
April	25,691	25,224	27,700	30,384	26,595	26,804	31,174	33,911	31,770	28,806	73%
May	27,741	25,141	30,628	30,110	34,396	24,798	34,698	39,808	37,808	31,681	80%
June	33,279	33,616	34,692	33,607	32,472	29,281	40,937	43,630	39,762	35,697	90%
July	31,018	32,676	**39,567**	37,782	33,273	37,489	**45,884**	45,245	41,192	38,236	97%
August	**33,436**	**35,715**	39,449	**37,790**	**39,187**	**39,230**	44,006	**45,494**	**41,419**	**39,525**	100%
September	32,705	31,955	37,651	34,014	38,462	39,010	40,188	43,740	37,993	37,302	94%
October	30,288	26,707	32,784	32,419	31,289	27,564	36,772	35,712	38,806	32,482	82%
November	25,794	26,146	29,034	26,979	29,140	27,032	32,860	33,338	32,138	29,162	74%
December	26,908	27,357	30,184	27,823	28,403	29,299	34,432	34,115	33,347	30,208	76%

Table 5
Monthly Statewide Coincident Peak Electricity Demand Forecast 2002 (MW)

	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Baseline Forecast	41,101	46,312	51,277	51,277	51,277	42,141	37,833	39,189
Temperature Risk Adjustment	1,407	2,683	2,971	2,971	2,971	1,443		
Monthly Demand Forecast	**42,508**	**48,995**	**54,248**	**54,248**	**54,248**	**43,584**	**37,833**	**39,189**
Operating Reserve	2,636	3,063	3,443	3,443	3,443	2,768	2,365	2,460
Peak Demand + Reserves	**45,144**	**52,058**	**57,691**	**57,691**	**57,691**	**46,352**	**40,198**	**41,649**

May and October based on average % of 1-in-5 forecast
June based on average % of 1-in-10 forecast
July through September based on 1-in-10 forecast with peak assumed to be possible in any summer month.

Lines 3 and 4 Operating Reserves

Required operating reserves are determined using seven percent of the monthly peak load minus firm imports. Firm imports are subtracted because contracts require that they provide their own reserves.

Line 5 California Statewide Peak Demand plus Operating Reserve

This is the sum of the baseline forecast, weather adjustment and minimum required operating reserve requirements. This line represents the estimated statewide capacity requirement.

Line 6 and 7 Existing CA ISO Control Area Merchant and Municipal Thermal Resources

Existing California ISO control area merchant and municipal thermal resources are based on installed generation as of December 31, 2001. Thermal unit capacity is derated to reflect summer operating conditions. The summer derate capacity can range from 90 to 96 percent of nameplate capacity based on the type of unit and location. It should be noted that some of the instate generation resources are sold into the market and may be sold to buyers outside California.

Lines 8 CA ISO Control Area Hydro Capacity

California's hydropower production system comprises a diverse mix of producers, infrastructure, dispatch policy and geography. California has 14,116 MW of installed hydropower capacity owned by: investor owned utilities (36%), state/federal water projects (27%), municipal utility districts (24%), water districts (7%), irrigation districts (5%) and miscellaneous (1%). [Source: Resources Agency March 29, 2001 filing to FERC in docket EL01-47-000, p. ii] Of this total, 11,200 MW of dependable capacity is located within the Independent System Operator's control area.

The energy from hydroelectric facilities, other than pumped storage units, is typically broken down into two components: run-of-river and pondage. The run-of-river generation is that amount of energy resulting from non-discretionary water flows that are necessary to meet hourly and daily requirements for downstream habitats, water delivery contracts, and flood control. Generation from the run-of-river portion of a hydroelectric facility is continuous at a relatively fixed output level, which is characteristic of a baseload plant.

Larger dams (high head) have additional storage capacity, or pondage, which allows the operator of the dam to control timing of water releases for electric generation. This flexibility in generation from the pondage portion of a dam gives it the characteristics of both an intermediate load following plant and a peaking plant. This flexibility also allows the pondage portion of a hydroelectric facility to serve both the energy and reliability needs of the system.

Of the 14,116 MW of hydropower capacity in California, 10% is in pumped storage and 62% is from facilities backed by sufficient reservoir storage to allow for operational flexibility. Storage gives California a significant ability to shape its hydro production, both as a part of economic operation and in times of peak demand. Under normal operations, units are run within multiple constraints for water management, downstream needs and environmental concerns. However, reliability needs and system operations economics can elicit a high use of hydro for a few hours for the peak period.

The ISO Control Area Hydro total is the sum of the identified dependable capacity for each individual facility during average water conditions. The historic record shows that the dependable hydropower capacity does not significantly change during a low water year, but may decline during a multiple year drought. The hydropower capacity is not derated.

But, adding up individual units overstates the actual operational capability of the hydro system during a particular peak period. For example, multiple turbines located on a single river system cannot receive maximum water at the same time. Line 15 accounts for these limitations.

Line 9 Investor-Owned Utility Retained Thermal Generation

Diablo Canyon and San Onofre Nuclear Generating Station, the two nuclear facilities located in California, make up the majority of the IOU retained generation with 4,364 MW of dependable capacity. Southern California Edison's (SCE) ownership portion of the Mohave Power Plant and a few small plants not divested by the IOUs are also included.

Line 10 CA ISO Control Area Firm Imports

The ISO Control Area Net Imports only include the power associated with firm contracts or utility ownership of resources located outside California. This differs from the reported ISO summary trends, which include both firm and shorter-term deals. Staff instead includes a conservative estimate of expected spot market imports for 2002 in **Line 28**, **Expected Spot Market Imports**.

To calculate CA ISO Net Imports, staff evaluated firm contract totals with Bonneville Power Administration (BPA) and out-of-state utilities, out-of-state resources owned by California utilities and entitlements to federal resources such as Hoover. **Table 6** includes the amount of power that is dynamically scheduled by the ISO. These generation resources are geographically located outside of the ISO control area, but scheduled by the ISO for imports. **Table 7** provides the list of firm power contracts for both imports and exports. **Table 8** includes the municipal utility ownership shares of the generation facilities located outside of California and their federal resource entitlements. **Table 9** provides a summary of the imports and export estimates to derive the net firm imports.

Table 6
ISO Dynamically Scheduled Resources (MW)

SCE Ownership Portion of Palo Verde	606
SCE Ownership Portion of Four Corners	710
SCE Ownership Portion of Hoover	278
Metro Water District Portion of Hoover	248
Yuma Cogeneration	53
Total Dynamically Scheduled Resources	**1,895**

Table 7
Firm Imports and Exports Contracts (MW)

Import Contracts	
SCE Geothermal (MW)	
Imperial Valley	440
Total	**440**
BPA to CA Munis	230
BPA to SCE	500
Deseret GandT To CA Munis	92
Pacific NW to CA Munis	254
Pacific NW to CA IOUs deliver at COB	475
PacifiCorp UT to SCE at 4 Corners	100
PacifiCorp NW to CDWR	300
LADWP to CDWR	77
Total	**2,098**
Export Contracts	
SCE to Southwest	(105)
Total Exports	**(105)**

Table 8
CA ISO Municipal Owned Out-of-State Resources (MW)

Pasadena Palo Verde	10
Riverside Palo Verde	12
Vernon Palo Verde	11
SCE.Other Palo Verde	7
Anaheim Hoover	40
Azusa Hoover	4
Banning Hoover	2
Colton Hoover	3
Pasadena Hoover	20
Riverside Hoover	29
Vernon	22
San Juan 3 – 4	278
Intermountain 1 – 2	414
Parker - Metro Water District	51
Total	**903**

Table 9
Summary of Net Firm Imports (MW)

Total Dynamically Scheduled	1,895
CA ISO Utility Owned Out-of-State Resources	903
Contracts	2,098
SCE Out-of-Control Area QF Geothermal	440
Firm Exports	(105)
Total Net Firm Imports	**5,231**

Line 11 Dependable QF Capacity

Dependable Qualifying Facility (QF) capacity data is calculated from confidential information received from the IOUs by subpoena. This is the most complete QF data source available to the Energy Commission. QF resources are contracted to the IOUs and are not sold elsewhere or exported. The majority of monthly variation in dependable capacity is found in the small hydro and solar assets. Dependable wind capacity is significantly lower than installed capacity due to daily and seasonal variations in wind patterns. QFs experienced a high amount of planned outages between fall 2000 and spring 2001 due to temporary payment problems. These problems have been resolved.

Lines 12 and 13 CA Municipal Resources not in the ISO Control Area

Municipal resource data is based on installed generation as of December 31, 2001. Thermal unit capacity is derated to reflect summer operating conditions. Excess municipal capacity can be sold in the California market or to out-of-state purchasers.

Line 14 Sum of Existing Resources and Dependable Imports

This is the total existing resources and firm power imports available to meet California peak electricity demand for the summer 2002.

Line 15 Hydro Derate

The sum of the dependable capacity needs to be derated to reflect the expected availability during peak demand periods. The total dependable hydro capacity used in the existing resource tally is the sum of the individual hydro facility estimates, but does not represent the actual operational capability of the whole system during a particular period.

Some of the hydroelectric facilities have generated more than the actual nameplate capacity, when extra amounts of water were available. Many hydroelectric facility operators derate individual facilities to derive the dependable capacity during average conditions, considering numerous factors. Some of these factors include varying environmental conditions, overall water basin conditions and even for temperature changes. The criteria for calculating the dependable capacity is not consistent from one facility to the next and may not reflect the actual capability when coordinating upstream facility operations during a particular peak period.

The 2,500 MW derate was derived by comparing historical operational data to the available generation capacity, with some additional adjustments that were based on discussions with system operators.

The 2,500 MW derate was then adjusted to reflect additional hydroelectric capacity that can be available for several peak hours during the summer. ISO hourly data for 2001 provided the basis to derive a summer peak availability estimate. The ISO and Energy Commission Staff agreed that 1,000 MW of additional hydroelectric capacity would be available during the summer, so the total summer derate to the dependable capacity was calculated to be 1,500 MW.

The net result of using these derates with the dependable capacity listed in line 8 is similar to the total available hydropower capacity that the ISO reports in their summer assessment.

Line 16 Estimated Nuclear Offline

Nuclear power plants typically operate on an 18-month cycle after which they must replace their nuclear fuel. These outages usually last 30-45 days and include refueling, maintenance, and repair activities.

Because of the recent discovery of severe corrosion in the reactor pressure vessel head at an Ohio nuclear power plant (Davis-Besse) during their refueling and maintenance outage, the Nuclear Regulatory Commission (NRC) has ordered all pressurized water reactors to check for corrosion.

California plants are younger than the Davis-Besse plant and are considered less likely to have similar problems. Using NRC's rating system for susceptibility to degradation, San Onofre and Diablo Canyon were given a Category 3 rating (Categories 1-4 with Category 1 being the most severe).

Two California nuclear units are scheduled for routine refueling outages during the spring of 2002. These outages will have about one week of overlap. Both units will inspect their reactor lids during their scheduled refueling and maintenance outages.

Line 17 Economic Outages

A line is included for potential economic outages, however staff does not expect any outages for this category during peak periods. The CA ISO generally gives permission for these outages after assessing the likely need for these slow start units. Staff assumed during periods of peak demand, the CA ISO would not approve any economic outages.

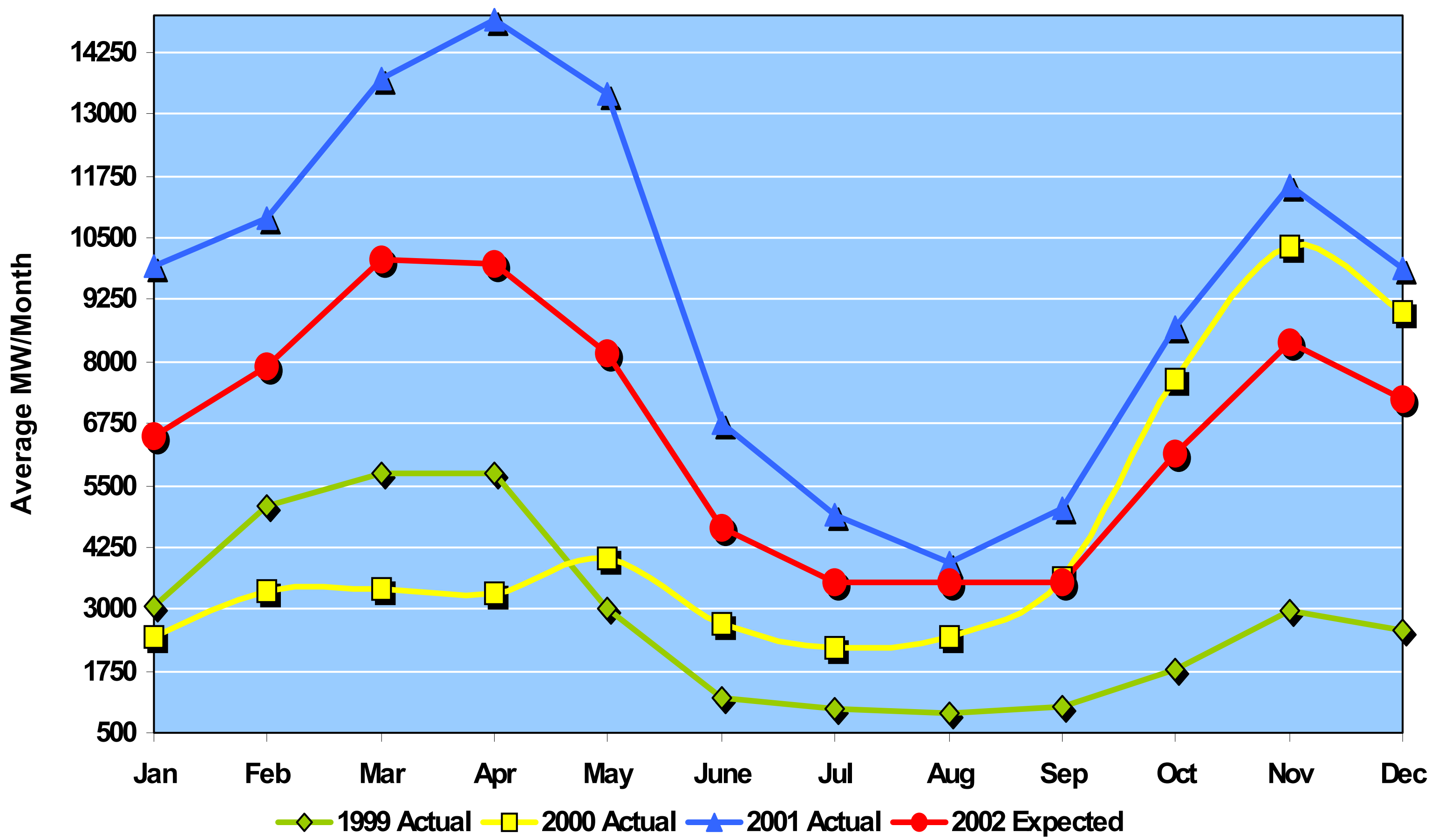
Line 18 SCR Retrofit

Several power plants are scheduled for planned maintenance to add Selective Catalytic Reduction (SCR) equipment in order to comply with local air quality standards. This line provides an estimate of these scheduled outages.

Line 19 Estimated Outages

Estimated Outages include all forced outages and planned outages except nuclear refueling and SCR Retrofits. **Figure 4** compares January 1999 through December 2001 statewide historical monthly average outages and the 2002 forecast outages for comparison.

Figure 4
Historical and 2002 Expected Statewide Monthly Average Outages (MW)



Source of Historical Outages: CA ISO Projected Daily Operating Loads and Resources Report. Data is from the previous day's actual portion of report and includes economic outages.

Staff used the average actual outages from 1999 through 2001 reported by the ISO to estimate outages for May and for October through December. The ISO reports that the 1999 and 2000 outage record may be incomplete. The 2001 ISO outage record also includes economic outages. Hydro derate is not included as an outage in this chart During the summer peak months of June through September, staff used 3,000 MW for CA ISO control area resource outages and 550 MW for resource outages outside the CA ISO control area. The California ISO 2002 Summer Assessment also assumes 3,000 MW of forced outages within their control area.

Line 20 Sum of Estimated Outages and Hydro Derate

This line provides the total outages and hydro derates that are used for calculating the available resources for meeting peak demand.

Line 21 Existing Resources Available to Meet Load

Calculated by subtracting the estimated forced and scheduled outages (**Line 20)** from the total estimated resources and imports (**Line 14**).

Line 22 Resource Surplus/Deficit before New Additions

This interim supply/demand balance is calculated by subtracting California statewide peak demand plus operating reserves (**Line 5**) from existing resources available to meet load (**Line 21**). This provides the expected resource surplus or deficit before new generation additions, demand response programs and expected spot market imports.

Lines 23 and 24 New Generation Additions

New generation capacity is expected to increase by 3,184 MW in 2002. The majority of this new generation capacity (2,586 MW) is scheduled to be online before August, including 2,111 MW of new combined cycle power plants and 424 MW coming from new peaker units and co-generation facilities. The remaining capacity is from renewable programs and restarting existing facilities.

A detailed listing of all facilities staff considered having a 75% probability of meeting their projected online dates is included in **Table 10.**

Table 10
New Additions Expected Online in 2002 (MW)

Project	Capacity	Derated	Online	Cumulative
El Segundo	10.0	10.0	1/1/02 Complete	
	January	**10.0**		**10.0**
City and County of San Fran Project (DIGESTER GAS)	2.1	2.1	1/15/02 Complete	
	February	**2.1**		**12.1**
Calpine Gilroy Phase 3	45.0	40.1	2/18/02 Complete	
Calpine King City	50.0	44.5	3/1/02 Complete	
	March	**84.6**		**96.6**
Energy Transfer/Hanover	23.0	21.0	4/1/02 Complete	
	April	**21.0**		**117.6**
Delta - Calpine	880.0	843.9	5/1/02 Commissioning	
	May	**843.9**		**961.5**
CalPeak/El Cajon	49.5	49.5	6/1/02	
Redding	54.0	54.0	6/1/02	
CalPeak/Vaca-Dixon	49.0	49.0	6/1/02	
Moss Landing I	530.0	508.3	6/1/02	
Valero Refining - Valero Cogeneration I	51.0	45.4	6/1/02	
El Segundo	8.0	8.0	6/1/02	
	June	**714.2**		**1675.7**
Calpine Yuba	45.0	40.0	6/14/02	
Moss Landing II	530.0	508.3	7/1/02	
	July	**548.3**		**2224.0**
Jackson Valley	18.0	18.0	7/15/02	
Mark Tech./FORAS Energy, Inc., Alta Mesa VII (WIND)	15.0	4.5	7/15/02	
La Paloma I	262.0	251.0	7/26/02	
GWF Henrietta (Lemoore)	91.0	81.0	8/1/02	
Mark Tech./FORAS Energy, Inc., Alta Mesa IV (WIND)	25.2	7.6	8/1/02	
	August	**362.1**		**2586.0**
La Paloma II	262.0	251.0	8/23/02	
Energy Developments, Inc., Chateau Fresno (LFG)	2.6	2.6	9/1/02	
Energy Developments, Inc., Keller Canyon (LFG)	3.9	3.9	9/1/02	
Energy Developments, Inc., Azusa (LFG)	5.2	5.2	9/1/02	
Cabazon Wind Partners, LLC (WIND)	43.0	12.9	9/1/02	
Wintec Energy #2 (WIND)	3.8	1.1	9/1/02	
Republic, Vasco Road (LFG)	4.5	4.5	9/1/02	
	September	**281.2**		**2867.2**
La Paloma III	262.0	251.0	9/10/02	
El Dorado Irrigation (Small Hydro)	21.0	21.0	9/18/02	
	October	**272.0**		**3139.2**
La Paloma IV	262.0	251.0	7/4/02	
ISG, Energy LLC, Mesquite Lake Recovery (Waste Tire)	30.0	30.0	11/1/02	
Keating (Small Hydro)	1.0	1.0	11/1/02	
	November	**31.0**		**3170.2**
Calwind Resources (Wind)	8.6	2.6	12/1/02	
NEO Corporation, Milliken (LFG)	5.0	5.0	12/1/02	
NEO Corporation, Colton (LFG)	2.5	2.5	12/1/02	
NEO Corporation, Mid-Valley (LFG)	3.8	3.8	12/1/02	
	December	**13.9**		**3184.1**

Line 25 Resource Surplus/Deficit

This line is the sum of resource surplus/deficit before additions **(Line 22)** and the 2002 generation additions considered to have a 75% probability of meeting their online date **(Line 23)**. This provides the expected resource surplus or deficit before demand response programs and expected spot market imports.

Lines 26 and 27 Reserve Margins

Line 26 provides the monthly peak reserve margin under average temperature conditions. **Line 27** represents the reserve margin under very hot summer conditions (1-in-10 probability). When reserve margins fall below the WSCC Minimum Operating Reserve Criteria (MORC) the CA ISO will declare one of the following emergencies:

- **Stage 1:** Actual or anticipated operating reserves are less than the MORC;
- **Stage 2:** Actual or anticipated operating reserves are less than or equal to five percent (5%);
- **Stage 3:** Actual or anticipated operating reserves are less than or equal to one and one half percent (1.5%).

Line 28 Expected Spot Market Imports

A line is included to provide staff's estimate of available out-of-state spot market imports. This line provides a conservative estimate based on historical import levels, adjusted to account for recent changes in supply and demand in neighboring regions.

The CA ISO notes that 6,200 MW of imports were available during the annual peak in August 2001. Staff estimates that 1,200 MW of this total was actually spot market imports. Improved hydro conditions in the Northwest and the addition of more than 4,000 MW of efficient gas-fired capacity in neighboring states since Summer 2001 results in a minimum of a 1,500 MW increase in import potential from these regions. This increase yields an estimate of 2,700 MW in spot market imports.

Line 29 Resource Surplus/Deficit with Expected Spot Market Imports

This is the sum of expected spot market imports and **Line 25**.

Line 30 1-in-10 Reserve Margin Including Expected Spot Market Imports

This line illustrates the effect of including 2,700 MW of spot market imports as a resource when calculating reserve margins.

Lines 31 - 35 Demand-Response Programs (DRP)

The 2002 DRP assumptions that staff used in the forecast are included in **Table 11**. Several DRPs are still in the early stages of implementation and their total impact may not be fully realized in the Supply/Demand Balance. Some of these programs are CEC proposed modifications to the curtailable programs, new public awareness programs and new legislation. The Demand Reserve Power Purchase Program proposed by the California Power Authority could provide an additional 900 MW of demand response by September 2002 if finalized.

Table 11
2002 Demand Responsiveness Programs (MW)

		May	June	July	August	September	October	November	December
	Ongoing Programs								
	Scheduled Load Reduction Program	4	4	4	4	4	4	4	4
	Discretionary Load Curtailment Program	0	0	0	0	0	0	0	0
32	**Ongoing Subtotal**	**4**	**4**	**4**	**4**	**4**	**4**	**4**	**4**
	Interruptible/Emergency Programs								
	Demand Bidding Program	0	33	33	33	33	-	-	-
	Existing Interruptible Program	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009
	Base Interruptible Program	3	3	3	3	3	3	3	3
	Ag Pumping	42	42	42	42	42	42	42	42
	AC Cycling		254	254	254	254			
	Optional Binding Mandatory Curtailment	41	41	41	41	41	41	41	41
33	**Interruptible/Emergency Programs Total**	**1,096**	**1,382**	**1,382**	**1,382**	**1,382**	**1,096**	**1,096**	**1,096**
	Existing Voluntary/Emergency Programs								
	State Building Demand Response	150	150	150	150	150	150	150	150
	DWR Peak Load Reductions*	300	300	300	300	300	300	300	300
	Federal and Local Demand Reduction	208	208	208	208	208	208	208	208
34	**Existing Voluntary/Emergency Programs Total**	**658**	**658**	**658**	**658**	**658**	**658**	**658**	**658**
35	**Total Additional Demand Reduction Impacts**	**1,758**	**2,044**	**2,044**	**2,044**	**2,044**	**1,758**	**1,758**	**1,758**

*DWR Peak Load Reductions up to 300 MW based on system conditions

Line 36 Resource Surplus/Deficit

This is the sum of the demand response programs and **Line 29**. This total provides the difference between resources (including demand response) and peak demand plus required operating reserves.

Comparison with the November 2001 Preliminary Outlook Report

Table 12 compares actual 2002 data through April 30 and the November 2001 version of the *2002 Monthly Electricity Forecast: California Supply/Demand Capacity Balances for January - September 2002*. Actual 2002 data is based on information contained in the California ISO's *Projected Daily Operating Loads and Resources, Winter Report.* Actual California outages include an undisclosed number of authorized economic outages.

Table 12
Comparing November 2001 Outlook Against
Actual Data for January - April

	Forecast	**Actual**
January 2002		January 29
CA Peak Demand	37,396	38,979
CA Operating Reserve	2,357	3,809
CA Outages*	9,039	11,246
Meet Reserve Requirements	Yes	Yes
February 2002		February 7
CA Peak Demand	36,218	37,004
CA Operating Reserve	2,274	3,894
CA Outages*	10,014	12,693
Meet Reserve Requirements	Yes	Yes
March 2002		March 18
CA Peak Demand	36,035	36,318
CA Operating Reserve	2,261	3,319
CA Outages*	11,186	16,637
Meet Reserve Requirements	Yes	Yes
April 2002		April 24
CA Peak Demand	37,194	37,080
CA Operating Reserve	2,343	2,946
CA Outages*	11,882	10,657
Meet Reserve Requirements	Yes	Yes

* Forecast Outages = planned and forced
  Actual Outages = planned, forced and authorized economic

Table 13 compares the November 2001 forecast for peak summer months to the current outlook and **Table 14** summarizes the differences between the outlooks. The biggest change in the two outlooks is the delay in new generation coming online. The Huntington Beach plant (450 MW) is no longer included, though the plant's owner may bring it on line later this summer. The phase-in dates for the La Paloma 1 - 4 units (251 MW each) have been delayed by more than two months.

Table 13
Comparison of November 2001 Outlook and Current outlook

	November 2001 Outlook				Current Outlook			
	Jun-02	Jul-02	Aug-02	Sep-02	Jun-02	Jul-02	Aug-02	Sep-02
California Statewide Peak Demand + Operating Reserve	51,937	57,691	57,691	57,691	52,058	57,691	57,691	57,691
Existing Resources and Dependable Imports	59,427	59,387	59,339	59,235	59,190	59,169	59,128	59,059
Estimated Forced & Scheduled Outages	(5,375)	(5,375)	(5,050)	(5,050)	(7,211)	(5,050)	(5,050)	(5,050)
Existing Resources Available to Meet Load	54,052	54,012	54,289	54,185	51,979	54,119	54,078	54,009
November & December 2001 Additions	518	518	518	518	Included in existing resources			
2002 Additions	2,936	3,498	3,749	3,749	1,676	2,224	2,586	2,867
Resource Surplus/Deficit Before Demand Response or Spot Market Imports	5,568	337	866	762	1,596	(1,348)	(1,027)	(815)
Expected Spot Market Imports	Not included in NovemberOutlook				2,700	2,700	2,700	2,700
1-in-10 Reserve Margin Including Expected Spot Market Imports	Not included in November Outlook				17%	10%	10%	11%
Resource Surplus/Deficit Before Demand Response	5,568	337	866	762	4,296	1,352	1,673	1,885
Demand Responsive Program Total	1,699	1,699	1,699	1,699	2,044	2,044	2,044	2,044
Resource Surplus/Deficit	7,267	2,036	2,565	2,461	6,340	3,396	3,717	3,929

The current outlook's existing resources and dependable imports line incorporates November and December 2001 additions and removes about 700 MW for retired units. Estimated forced and scheduled outages have been updated to reflect more current information on nuclear refueling and SCR retrofit planned outages.

Table 14
Summary of Changes to November 2001 Outlook

	Difference in Outlook				Comments
	Jun-02	Jul-02	Aug-02	Sep-02	
California Statewide Peak Demand + Operating Reserve	121	0	0	0	
Existing Resources and Dependable Imports	(237)	(218)	(211)	(176)	Retired approximately 700 MW
Estimated Forced & Scheduled Outages	(1,836)	325	0	0	Update nuclear refueling & SCR
Existing Resources Available to Meet Load	(2,073)	107	(211)	(176)	
November & December 2001 Additions	(518)	(518)	(518)	(518)	Included in existing resources
2002 Additions	(1,260)	(1,274)	(1,163)	(882)	Delays in two major units
Resource Surplus/Deficit Before Demand Response or Spot Market Imports	(3,972)	(1,685)	(1,893)	(1,577)	
Expected Spot Market Imports	2700	2700	2700	2700	New line in current outlook
1-in-10 Reserve Margin Including Expected Spot Market Imports	17%	10%	10%	11%	New line in current outlook
Resource Surplus/Deficit Before Demand Response	(1,272)	1,015	807	1,123	New line in current outlook
Demand Responsive Program Total	345	345	345	345	
Resource Surplus/Deficit w/o Spot Imports (Not included to provide equal comparison)	(3,627)	(1,340)	(1,548)	(1,232)	Majority due to retirements & delayed 2002 additions

Comparison with the California ISO 2002 Summer Assessment

The California ISO recently completed an independent assessment of supply adequacy within their control area. **Table 15** compares the ISO 2002 Summer Assessment[3] to the California Energy Commission Monthly Electricity Forecast for the summer peak months. A brief discussion of areas with large differences is provided below. A copy of the ISO assessment can be downloaded from www.caiso.com/docs/2002/04/19/2002041917130017460.pdf

The data used for the Energy Commission portion of the table represent staff's estimates of demand and resources only within the CA ISO Control Area. Los Angeles Department of Water and Power, Imperial Irrigation District, Sierra Pacific and PacifiCorp also have control areas within California and their estimated demand and resources have been subtracted from the data presented in **Table 1**.

Line 1: The ISO Baseline operating load forecast of average temperatures and 1.5% economic growth rate is very comparable to the Energy Commission 1-in-2, most likely conservation forecast. The largest difference in the two outlooks is in what month the peak demand occurs. The summer peak demand has a higher probability of occurring in August based on actual monthly peak load history, however, it can occur anytime between July and September. The ISO forecast model uses the probability that the summer peak will be in August and the Energy Commission shows the peak possible July - September.

Line 4: Approximately 700 MW of retirements and environmental constraints reduce the Energy Commission's Net Dependable Capacity number. The ISO includes these as separate line items (**Lines 11 and 12**).

Line 6: The majority of the difference in the new generation is in the estimated online dates for the four units of La Paloma. The ISO estimates the first unit parallel date as March 24, 2002 with the other three to follow in May, July and August. The Energy Commission estimates the commercial operation date of July 26, 2002 for the first unit and the remaining three in August, September and October. There are some additional differences in online dates for smaller units and the ISO may have additional information on plants not permitted by the Energy Commission (below 50 MW).

Line 8: The ISO reports some scheduled thermal outages extending into early June that the Energy Commission has coming back online for June 1. The ISO has also included a nuclear outage into early July and the Energy Commission has the unit coming back online by July 1.

[3] California ISO 2002 Summer Assessment, Version 1.0, April 25, 2002.

Table 15
Comparison of the California Energy Commission and CA ISO Summer Outlooks for the ISO Control Area

	CA ISO Forecast				CEC Forecast				CEC + or -			
	Jun-02	Jul-02	Aug-02	Sep-02	Jun-02	Jul-02	Aug-02	Sep-02	Jun-02	Jul-02	Aug-02	Sep-02
1 Forecast Peak Demand	40,834	42,361	44,458	39,247	40,402	44,734	44,734	44,734	(432)	2,373	276	5,487
2 Operating Reserve Requirement	2,450	2,542	2,667	2,355	2,462	2,765	2,765	2,765	12	223	98	410
3 Estimated Control Area Capacity Requirement	43,284	44,903	47,125	41,602	42,864	47,499	47,499	47,499	(420)	2,596	374	5,897
4 Max Net Dependable Capacity (exc QFs)	39,883	39,883	39,883	39,883	38,865	38,854	38,837	38,805	(1,018)	(1,029)	(1,046)	(1,078)
5 Expected Net Avail QF	6,000	6,000	6,000	6,000	5,999	5,973	5,948	5,911	(1)	(27)	(52)	(89)
6 Accumulative New Generation	2,961	2,978	3,233	3,488	1,676	2,224	2,586	2,867	(1,285)	(754)	(647)	(621)
7 Dynamic Schedules int the ISO Control Area	1,906	1,906	1,906	1,906	1,895	1,895	1,895	1,895	(11)	(11)	(11)	(11)
8 Planned & Unplaned Scheduled Outages	(3,627)	(1,269)	(127)	(396)	(2,161)	0	0	0	1,466	1,269	127	396
9 Forced Outages	(3,000)	(3,000)	(3,000)	(3,000)	(3,050)	(3,050)	(3,050)	(3,050)	(50)	(50)	(50)	(50)
10 Hydro Limitations	(2,000)	(2,000)	(2,000)	(2,000)	(1,500)	(1,500)	(1,500)	(1,500)	500	500	500	500
11 Retirements	(318)	(318)	(318)	(318)	included in line 4				(318)	(318)	(318)	(318)
12 Environmental Constraints	(855)	(855)	(855)	(855)	included in line 4				(855)	(855)	(855)	(855)
13 Est Control Area Resource Capacity (at Peak)	40,950	43,325	44,722	44,708	41,724	44,396	44,716	44,928	774	1,071	(6)	220
14 Surplus/Deficiency (Before Firm Imports)	(2,334)	(1,578)	(2,403)	3,106	(1,140)	(3,103)	(2,783)	(2,571)	1,194	(1,525)	(380)	(5,677)
15 Expected Net Imports (Exc Dynamics)	3,500	3,500	3,500	3,500	3,336	3,336	3,336	3,336	(164)	(164)	(164)	(164)
16 Surplus/Deficiency (After Firm Imports)	**1,166**	**1,922**	**1,097**	**6,606**	**2,196**	**233**	**553**	**765**	**1,030**	**(1,689)**	**(544)**	**(5,841)**
1-in-10 Weather Adjustment	not forecast				2,384	2,640	2,640	2,640	2,384	2,640	2,640	2,640
1-in-10 Reserve Adjustment	not forecast				167	185	185	185	167	185	185	185
1-in-10 Surplus/Deficiency (After Firm Imports)	not forecast				(355)	(2,592)	(2,272)	(2,060)	(355)	(2,592)	(2,272)	(2,060)
Expected Spot Market Imports	not forecast				2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700
Surplus/Deficiency	**1,166**	**1,922**	**1,097**	**6,606**	**2,345**	**108**	**428**	**640**	**1,179**	**(1,814)**	**(669)**	**(5,966)**